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Imaging Geothermal Resources with 3D Seismic Attributes

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ABSTRACT

Seismic reflection surveys are underutilized by the geothermal industry as an exploration tool. New interpretational techniques applied to high quality data demonstrate that useful structural and lithologic data can be obtained, even in complex geologic environments. In this paper, we illustrate the application of seismic data in an exploration program where deep drill holes are available for validation. In this investigation, a set of 3D seismic attributes was extracted from a 3D seismic cube acquired over a geothermal area. The survey covers an area of approximately seven square miles. After processing in the depth domain, a process flow was designed to automatically analyze the attributes over the 3D volume and map the occurrence of anomalous zones using thresholding based on pre-determined values. Tests of the algorithm proved that it was capable of mapping known horizons in a robust manner. Cross-plots of pairs of attributes were calculated and compared with known permeable zones identified from well data.

1. INTRODUCTION

Seismic reflection is frequently used to image the sub-surface from depths ranging from centimeters to kilometers (Sheriff and Geldart, 1995). In particular, it is widely used in the petroleum industry (Ikelle and Amundsen, 2005) where significant investment over many years has made seismic reflection the primary tool used in exploration and production, as it possesses higher resolution and greater penetration than other geophysical methods. 3D surveys tend to be the standard in the petroleum industry, as 2D surveys suffer from artifacts and lack the precision needed for accurate well location. 3D surveys are also used in mineral exploration (Malehmir et al., 2012). The use of 3D seismic reflection surveys is becoming more common in geothermal exploration (Louie et al., 2011; Majer, 2003). Newer technology, such as wireless sensors and low-cost high performance computing, has helped reduce the cost and effort needed to conduct 3D surveys and use in geothermal exploration is expected to expand in the future.

The method images the subsurface structure by measuring the timing and amplitude of reflected seismic waves. Substantial processing is required to generate an image from the original data. The simplest form of interpretation uses the seismic amplitudes as a function of time (or depth) to estimate sub-surface structure. More advanced interpretation uses other characteristics (attributes) of the seismic traces to infer additional constraints on the sub-surface. Considerable work in this area has been conducted by the petroleum industry in refining this type of analysis and it has led in some cases to significant improvement in exploration success rates.

In this work, we seek to apply these advanced techniques to improve detection and characterization of geothermal resources. As the cost of a seismic reflection survey is generally less than that of a single test drill hole, an improved ability to detect and assess geothermal resources should lead to lower costs in geothermal exploration and production. This goal is challenging, as geothermal resources often occur in structurally complex areas and often in volcanic rocks, which increases the difficulty of obtaining high-quality images. Although less costly than drilling, the cost of acquisition and processing a 3D survey remains substantial.

The specific objective is to develop a process to reduce the risk associated with drilling additional production wells. As a test-bed, we will use a dataset of 3D seismic reflection data and ancillary well data from the Raft River geothermal area, Idaho. The 3D dataset from Raft River was acquired and processed by Optim, Inc. An area of approximately 7 square miles was covered. The intent is to find an attribute, or combination of attributes, that allows specific parameters relevant to geothermal production to be estimated throughout the volume of the survey. This will allow better estimates of the expected geothermal production at a specific site prior to drilling.

In parallel with the seismic analysis, log and mineralogy data (Jones et al., 2011) from the wells will be collected to validate the results. The goal is to determine a quantifiable relationship between a seismic attribute (or multiple attributes) and a specific parameter measured in the well (i.e productivity index). Once the relationship is estimated, perhaps by using a crossplot, the specific parameter(s) can then be estimated at every other point covered by the 3D survey. This will be used to infer regions of expected high productivity that may be candidate drill sites.

2. SEISMIC ATTRIBUTES AND GEOTHERMAL AREAS

The primary goal in geothermal exploration is to find a location with sufficient temperature and permeability. Seismic wave propagation is largely insensitive to temperature variations and therefore indirect effects such as related changes in lithology or fractures must be found. Mineralization associated with water flow may increase velocities (Majer, 2004) while fractures are expected to decrease velocities and increase attenuation (Nakagone et al., 1998). The resolution of seismic surveys is much larger than the fracture size and therefore fractures cannot be imaged directly in most cases. Hydrothermal alteration may also decrease velocities (Unruh et al., 2001). In some cases where a clear fluid boundary exists, it may be possible to image the boundary. These effects are difficult to detect using standard interpretation based on amplitudes and attributes are one possible approach to extracting the information. Other approaches may be possible such as inverting for acoustic impedance for lithology, azimuthal variations in amplitude to infer fractures, or amplitude versus offset may be useful. The use of 3D component data for attenuation or anisotropy may be applicable.

Standard seismic reflection interpretation uses the amplitude of the reflected signal to infer subsurface features. Signal processing can extract other features from the wiggle in addition to amplitude. This may provide additional information. For example, the envelope of a trace is calculated by applying a Hilbert transform to the trace. Other commonly used attributes are instantaneous frequency and phase but many more exist (Barnes, 1999; 2006). Attributes can also be created by comparison of multiple traces. Coherence, which is widely used in the petroleum industry, measures the similarity between neighboring traces (Figure 2) (Marfurt, 2004). Coherency highlights spatial variations in the data, which might be caused by faults or other features (Chopra and Marfurt, 2007). More complicated attributes may combine multiple features. Curvature provides a measure of how much a specific horizon is warped. As each attribute provides different information, combinations of attributes can be useful to provide constraints on various physical parameters of the subsurface.

For the dataset in the study, once initial processing and depth migration was complete, a set of attributes was calculated for the dataset. This was conducted in several stages. Initially, the algorithms used to calculate the attributes were developed and tested on 2D data extracted from the 3D data cube. A set of 2D results was produced first for validation and then extended to the 3D cube. In parallel, attributes were also calculated using the Petrel seismic interpretation software as a means of validation. Figures 1, 2, and 3 show examples of coherency and acoustic impedance estimated for the 3D dataset. Associated well tracks are also shown, which will be the basis of validation using crossplots.

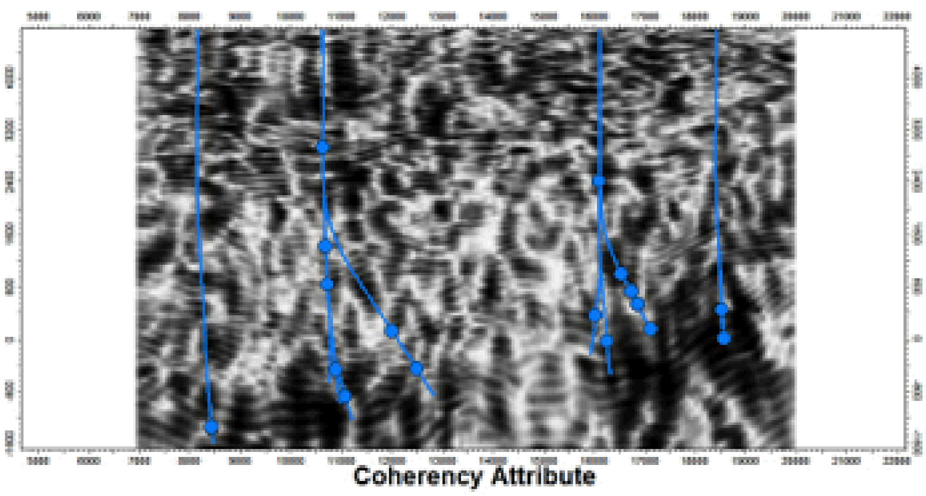

Figure 1: Inline showing coherency across the 3D dataset. Blue lines indicate well tracks that will be used for validation. Vertical axis is depth. White indicates relatively high coherency and dark low coherency. Wellbores (Blue) are projected on to the section.

The next step was to identify areas of interest by classifying the voxels (individual 3D data samples) to generate a process flow capable of automatically mapping the data into regions of interest. The advantage of automatic mapping is that it is fast, consistent, and avoids the bias associated with manual interpretation. Automatic mapping does require care in selecting thresholds and training sets The algorithm was designed to be sufficiently flexible to handle determination of multiple attributes. For ease of visualization, a simple 3D graphics package was built capable of displaying the seismic data and associated objects such as well tracks. Automated tracking for specific thresholds was also implemented.

Once the various attributes were calculated for the 3D cube, cross plots for pairs of attributes near wells were calculated and compared. The objective is to compare the various attributes with zones of known permeability and mineralogy. Figure 4 shows an example of a crossplot comparing known values from the well logs (density) with the acoustic slowness also estimated from the well logs. Once determined, this relationship can be used to estimate, the density throughout the entire 3D volume. Previously, it was only possible to estimate density in other areas by either drilling or extrapolating from the expected lithology, which yields a poor estimate.

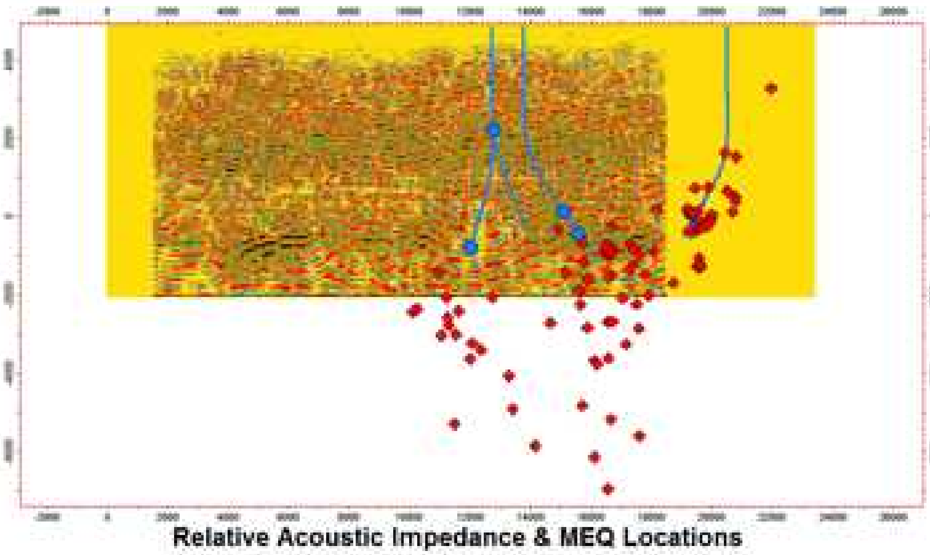

Figure 2: Figure showing acoustic impedance, well tracks (blue) and micro-earthquake locations plotted using hypocenters from the LBL catalog. Wellbores (Blue) are projected onto the section.

Efforts were made to generate full-wavefield synthetics of shot gathers using a finite-difference code (Sjogreen and Petersson, 2012) and the velocity model of Ackerman (1975). Synthetics were generated but lacked the higher frequencies necessary for a useful comparison. Higher frequencies required extensive computational resources and it was decided not to continuethis effort at the current time and focus on understanding the attributes. CDP gathers were not calculated.

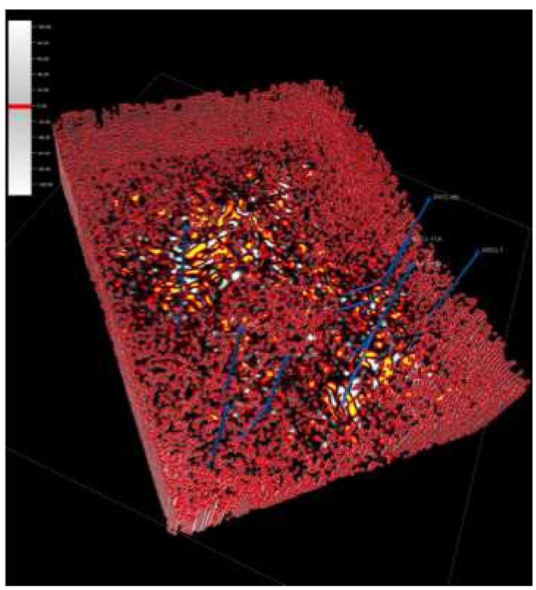

Figure 3: Perspective view of the 3D coherency cube of the geothermal area with well tracks shown in blue.

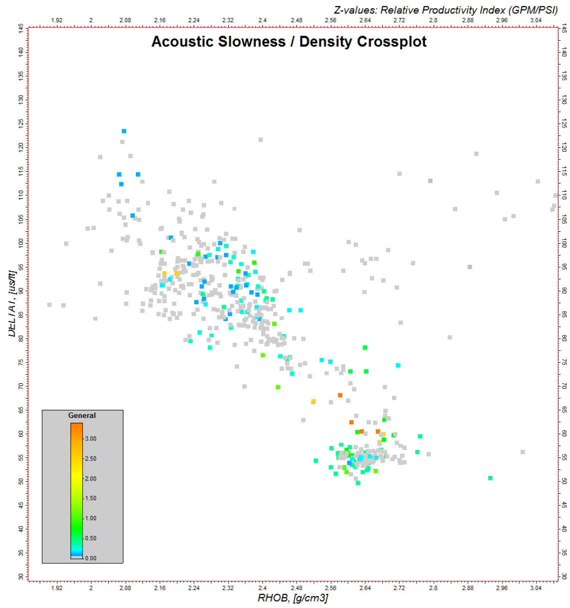

Figure 4: Figure showing acoustic impedance, well tracks (blue) and micro-earthquake locations plotted using hypocenters from the LBL catalog. Wellbores (Blue) are projected onto the section.

3. CONCLUSIONS

We are investigating the use of the 3D seismic attributes to evaluate a geothermal field. If robust relationships between seismic attributes and well productivity can be found and validated, this would be very useful in geothermal production and exploration.

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